To: Wang, Gary[wang.gary@epa.gov]
Cc: Gallant, William[Gallant.William@epa.gov]; Suchomel, Bruce[Suchomel.Bruce@epa.gov]; Breffle, Don[Breffle.Don@epa.gov]; Pardue-Welch, Kimberly[Pardue-Welch.Kimberly@epa.gov]; Rodrigo Jurado[rjurado@pgei.com]
From: Kevin Dickey
Sent: Tue 9/22/2015 1:33:40 PM
Subject: FW: Step rate test for Petroglyph's Ute Tribal 29-12 injection Well (EPA ID UT20736-04523
Antelope Creek Injection Water Analyses.pdf

Gary,

RE: Your September 11th email to Rodrigo Jurado denying Petroglyph's step rate request on the UT 29-12

I think we can agree on two points with respect to our step rate test on the UT 29-12 (plot below).

1. On our initial test using our water plant, the last point at 1711.5 psig was on the matrix trend line.

2. The first point on our test pumping water with the hot oiler at 1952.6 psig was not on the matrix trend line.

If this is the case, then we should, at a minimum, be allowed to inject into this well at pressures below 1711.5 psig as we clearly are not fracturing at this injection pressure.

As far as fluid characteristics coming into play, we are pumping water delivered by our injection system (both with the water plant and with the hot oiler). The TDS of our water barely changes between our different discharge facilities. Additionally, it doesn't matter if the tests are hours apart or days apart, as long as the rates and pressures have stabilized. If there is a flaw in our testing, in this instance, it is the length of the gap between point #5 and point #6. I understand this. But this was determined by the maximum plant output and the minimum hot oiler output.

But even so, we still see two distinct slopes:

•□□□□□□□□ Matrix slope: a 1 bwpd increase in injection raises the pressure 2.9 psi.

•□□□□□□□□ Fracturing slope: a 1 bwpd increase in injection raises the pressure 0.43 psi (nearly $1/7^{th}$ as much)

What we are trying to accomplish is to get accurate data for reasonable expense. In this case, I believe we have accomplished that. Downhole gages aren't the answer as the only difference between surface pressures and downhole pressures are fluid gradient and friction pressure. At the rates we are pumping, friction is negligible and can be ignored. With respect to the fluid gradient, our fluid ranges from 12,805-15,659 mg/l TDS (see attached water analyses). The densities range from 1.0061-1.0081 g/ml which is equivalent to 0.4356-0.4365 psi/ft. The maximum variance in downhole pressure due to changing water characteristics at the top perforation would be 4 psi (1,797-1,801psi) or 0.2%. Downhole gages would cost approximately $5,000 and would not significantly improve the data set, and would definitely limit the number of tests we could afford per annum.

Likewise, if we get Halliburton out to pump constant time intervals of 2 hours each, our cost would be over $5,000 (or over $10k for pump truck + downhole gages) and the accuracy of the test would be suspect as you can't get stabilized pressures at matrix rates in the Green River formation in such a short time period increments. We don't have a single reservoir, but rather multiple independent Green River reservoirs completed in one wellbore. It takes significant time for injection to stabilize through the multiple reservoirs, that's why the longer time intervals give better data. Once the well is fracturing, however, stabilized rates are easily obtained in much shorter time increments, as was seen in the results pumped by the hot oiler.

We would request an allowable injection rate of 1711 psig for the UT 29-12 injector, which is clearly on the matrix line. Since our plant can't pump steadily above this pressure at this location, this would be adequate for our present purposes. If we need to get a higher injection pressure, in the future, we will rerun the step rate test.

Thanks for your consideration,

Kevin

Kevin Dickey

VP Operations

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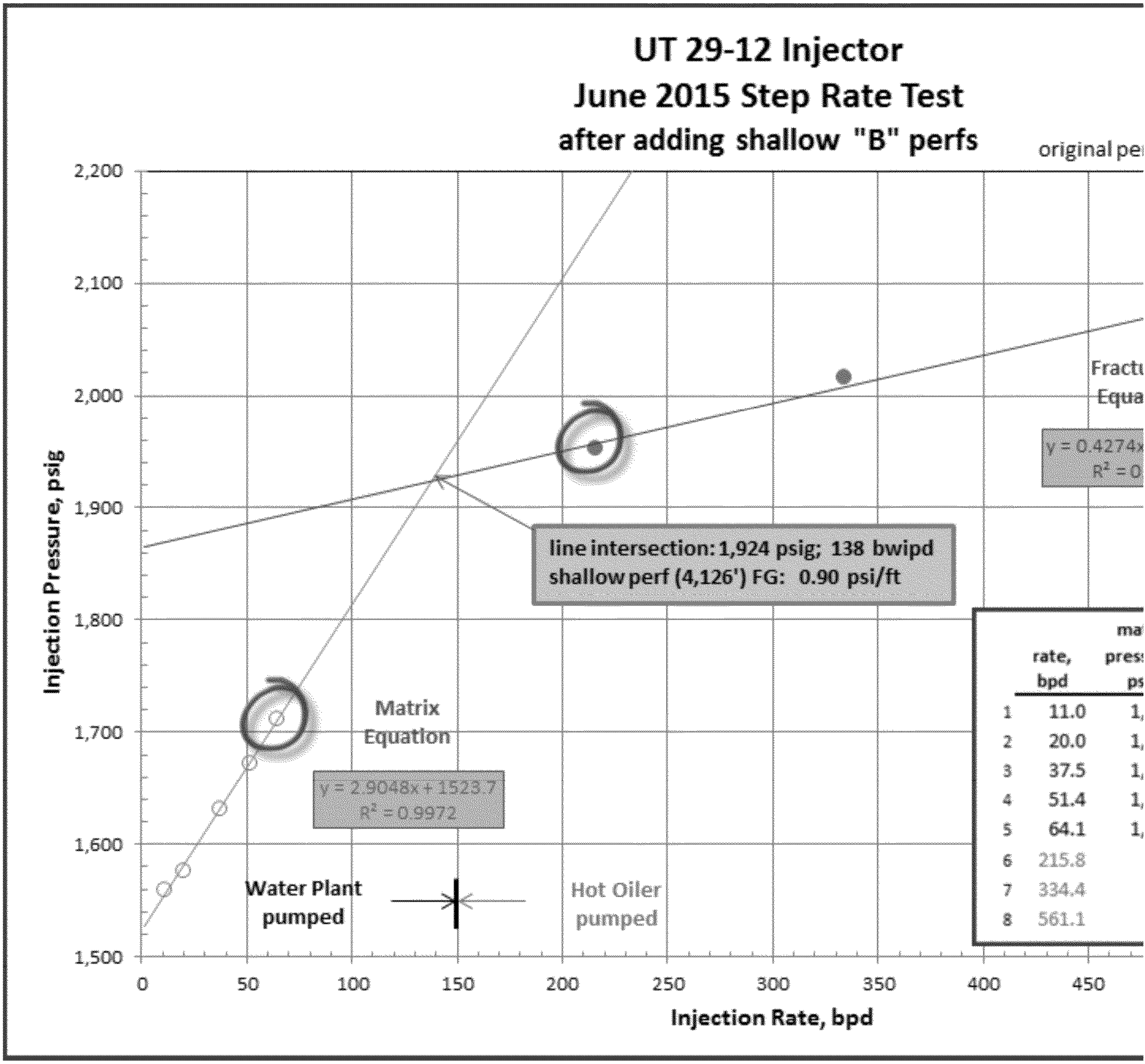
PETROGLYPH



From: Wang, Gary [mailto:wang.gary@epa.gov]
Sent: Friday, September 11, 2015 2:35 PM

To: Rodrigo Jurado
Cc: Breffle, Don; Pardue-Welch, Kimberly; Suchomel, Bruce; Gallant, William
Subject: Step rate test for Petroglyph's Ute Tribal 29-12 injection Well (EPA ID UT20736-04523

HI Rodrigo,

Per our conversation yesterday, Petroglyph submitted a step-rate test for the Ute Tribal 29-12 injection well in July 1, 2015. The step rate test conducted by Petroglyph was performed in two test events. The first event was conducted with fluid injected from the water plant pump, and a slope of a plot of pressure versus rate showed that the injection pressure remained below fracture parting pressure. The second event was conducted several weeks later with water injected from a hot oiler truck and a second slope was generated and assumed to be above fracture parting pressure because of the result of a different slope. The intersection for the two slopes were assumed by Petroglyph to be the well's surface fracture pressure.

Based on the review of the data, EPA is not approving the step rate test results based on the following reason:

- A breakdown point was not observed in either event. Because of the two separate events, the result from Petroglyph appear as two disparate slopes used to extrapolate the fracture pressure. Additionally, experimental conditions (e.g., fluid characteristics) may have changed between the two testing events.

We would like to see the step rate test be retested with the following conditions:

- The step rate test is to be conducted where the plot of the pressure versus rate is experimentally collected in one continuous event, beginning from below the fracture parting pressure, through the breakdown point, and into the above fracture parting pressure.

- After additional discussion with others in the office, we would also like to see both surface and bottom-hole pressures to be observed during the step rate test.

Please let me know if you have any questions.

Gary Wang
Underground Injection Control Enforcement

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